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Subject: Underground Injection Control Pre-Rulemaking Discussion Draft

Dear Mr. Harris,

EDF appreciates the opportunity to comment on the Division's proposals for updating its underground injection control rules, which include gas storage wells. The Division has an opportunity to develop a fully modern and robust regulatory program for both Class II wells and gas storage wells, which is very timely considering recent controversies in the state.

In late January, EDF commented on the Division's emergency gas storage regulations. We were glad that the Division adopted some of our suggestions but we noted in our comments that many topics critical to gas storage remained unaddressed. The discussion draft we are commenting on today goes a meaningful way toward addressing many of those issues, though we stress that there is more work to do on permanent gas storage rules, and likely through other rulemakings as well (e.g., general well construction rules).

EDF is generally supportive of the Division's efforts here. Most of the edits we provide are in service of clarifying or strengthening existing proposals. Changes proposed by the Division that should prove very useful include but are not limited to:

- Reduction in the speed for running temperature logging tool, which has been a problem in Aliso Canyon
- Annular pressure monitoring to identify potential loss of mechanical integrity
- AOR provisions to ensure containment of fluids
- Incident response requirements

EDF also urges the Division to give careful consideration to comments submitted by Clean Water Action and other groups. Those comments highlight important issues including on well construction, emergency response planning, and periodic regulatory review.

The remainder of today's comments is divided into three parts: (1) a description of revisions to the discussion draft we are suggesting at this time and why these changes are critical; (2) a partial list of issues not covered in the discussion draft that EDF believes must be addressed as soon as possible; and (3) a redline incorporating the amendments we are suggesting today.

(1) In order to reform the underground injection control rules to be fully environmentally protective and conform to national regulatory standards and industry leading practices, the Division should:

1. Update or clarify various definitions used in the rule. We have provided several definitions for terms used throughout the rule that might otherwise prove ambiguous, potentially leading to less protective outcomes. One key revision is in the definition of "underground injection project" to clarify that it refers to a mappable, three-dimensional, continuous physical space, necessary in order to make a proper Area of Review analysis without the possibility of internal holes within the project.

2. Reference gas storage withdrawal wells. These rules cover gas storage, and in many places the rule only references injection wells. In order to properly cover gas storage withdrawal wells, EDF has added references to them where appropriate.

3. Limit the ability for operators to transfer liability. The edits seek to ensure that operators remain liable to Division for adherence to Division rules and correction of any violations or other compliance issues associated with the project, and that liability does not pass to a new operator until all such issues have been resolved. This will help ensure that proper remediation occurs in a timely manner and potential pollution problems do not "fall through the cracks."

4. Ensure that existing projects meet the standards of the new rules. It is critical that all underground injection projects in the state meet the standards developed through this and subsequent rulemakings. Old wells should not be grandfathered in. Any well that cannot meet current standards should be remediated or properly plugged and abandoned. The Division's new standards for reopening Aliso Canyon wells recognize this principle. The edit gives one year for operators to meet the new standards at existing projects or to remediate or close the project. This timeline may be altered on good cause, and the Division may wish to develop distinct timelines for different types of projects or different parts of the rule, but the principle is that all projects should meet current standards.

5. Include language on non-endangerment of USDWs. This is a central theme in the Environmental Protection Agency's Underground Injection Control program. The concept of protecting USDWs is present in the rules as proposed, but EDF has made edits in appropriate sections throughout the proposed rule to enshrine the concept that protection must extend beyond freshwater of 3,000 TDS or less to all USDWs.

6. Add characteristics of reservoir to be reported. As part of the project data requirements, the Division proposed to request a variety of characteristics of the relevant reservoir to be reported. EDF adds seven additional properties that will be helpful for the Division to take into account when permitting underground injection projects in order to reduce the risk of pollution.

7. Clarify and enhance the Area of Review protocol. A robust Area of Review program is an essential part of ensuring that fluids remain confined to the target injection zone and do not migrate through conduits to protected water or the surface. EDF has provided a series of edits to clarify and strengthen the proposed protocol on the following topics:

    - Radius: allow the Division to change, on a well-by-well basis, the area under review as technically appropriate.

    - Analysis of offset wells: provide a more robust and nuanced framework for determining whether offset wells have sufficient cement across the proposed injection zone

    - Remediation of problematic offset wells: additional detail on how different types of wells should be handled, provides a greater role for the Division to consider and approve remediation or plugging plans, and enhances which zones should be isolated.

    - Field inspection of offset wells: provides the option for the Division to require periodic inspections of offset wells throughout the life of the project to look for evidence of loss of containment.

    - Faults and fractures: asks for more details about faults and fractures within the AOR that may act as conduits for fluid movement or otherwise compromise the integrity of the project.

8. Require a groundwater monitoring plan: the Division references the possibility of groundwater monitoring as part of an operator's injection plan. EDF's edits give the Division affirmative authority to require groundwater monitoring, and require the operator to submit a groundwater monitoring plan, including sampling and analytical methods to the Division for review. Groundwater monitoring is a technical activity that can vary in quality and effectiveness, and more Division oversight will ensure a more uniform and robust sampling protocol.

9. Give the Division oversight on reporting step rate data as representative: in many places in the rule, operators are allowed to make decisions that properly belong to the Division, or at least should have Division input. As an example, the proposed rule allows operators to choose which step rate data counts as representative in order to allow a determination of maximum allowable injection pressure. EDF's edit requires that the selection of representative step rate test data be made on a basis that is satisfactory to the Division. EDF has made similar recommendations throughout the proposed regulation and we encourage the Division to play a more active role in important project decision-making that could impact the environment.

10. Require universal automatic fail-safe shut-off safety systems: many commentators noted that a subsurface safety valve had been removed from the Aliso Canyon well in the 1970s, and wondered whether the presence of such a valve in working condition might have prevented the release that was only just capped. EDF understands that the investigation into the root cause of the accident is still underway, and until then it is difficult to say what kind of safety valve, if any, could have made a material difference. Nevertheless, the notion that some sort of safety system – whether a surface valve, a subsurface valve, or some other technology – ought to be part of every well's design is a solid and defensible one. EDF recognizes that these devices have and will evolve, and that the appropriate solution will vary on a well-by-well basis. EDF's language has the Division evaluate and approve the operator's proposed safety system solution, which it should do based on each well's geologic and operating conditions, and the Division's own expertise and experience.

11. Require testing of subsurface safety valves: for wells that do have subsurface safety valves, they need to be regularly calibrated and tested to be effective. EDF provides language to that end, referencing manufacturer and standard industry protocols.

12. Add various elements to wellbore diagrams: EDF's edits include several new data elements that should be reported to the Division so that it can more fully consider project proposals, like information about liners, tubing and packer, and confining zones.

13. Require certification for geologic and hydrogeologic evaluations: these evaluations, which are already required by the Division, are highly complex and technical. For high-pressure gas storage wells, they should be completed and certified by appropriate licensed professionals (either engineers or geologists). That will help ensure that the information received by the Division is accurate and sufficient to make smart permitting decisions. This requirement is consistent with rules in Kansas, which has some of the most robust gas storage rules in the country.

14. Require certification for new and converted well designs and condition: in a similar vein, the Division should require a signed and sealed certification from a professional engineer that new and converted gas storage wells are designed and constructed, and for converted wells maintained, in a way that makes them suitable for injection or withdrawal purposes. This is consistent with newly passed rules in Ohio on well pad construction, and is the best way to ensure that wells are appropriate for their proposed task. This is particularly critical for converted wells like the one at Aliso Canyon, which was converted from oil production to gas storage in the 1970s despite having a design apparently inappropriate for high-pressure gas injection and withdrawal.

15. Enhance step rate test requirements: EDF's edits provide clarity as to how to properly conduct step rate tests that are consistent with industry practices and regulatory requirements, and will help ensure that the proper pressure (i.e., that does not threaten formation integrity) is selected and used.

16. Provide a timeline for submitting changes to underground injection projects: EDF suggests 60 days to give the Division enough time to fully evaluate the proposed changes.

17. Require monitoring for pressure changes that might indicate a loss of mechanical integrity: this may be one of the most important edits in the document. One of the best ways of knowing whether a well has a mechanical integrity problem and thus may be leaking to the environment is to monitor annular pressure changes that may indicate a loss of integrity. The edits extend the Division's proposed requirement to specify that pressure monitoring devices be installed on the injection tubing and all casing annuli not cemented back to the surface, and for those devices to be continuously monitored for change indicating integrity loss. Note that the Division has not defined "continuous monitoring," though the phrase is used throughout Division rules; EDF has declined to provide its own definition but encourages the Division to develop one.

18. Require the use of a redundant wellhead valve system: these systems allow for safer well control, and, importantly, the ability to work on gas storage wells under pressurized conditions (e.g., with a snubbing unit).

19. Enhance the tubing and packer requirement by limiting exceptions: EDF appreciates the Division's general requirement that injection wells be equipped with tubing and packer, but the exceptions to this important requirement should be narrowed. All gas storage wells should be equipped with tubing and packer, with no exceptions. For Class II wells to receive exceptions, in addition to evidence that the proposed well design can protect USDWs, they should have at least two strings set below the USDW and cemented to surface, with at least one such string set to a depth where the casing shoe can withstand the maximum allowable injection pressure. Furthermore, the allowable pressure for such wells should not be able to overcome the hydrostatic head of the lowermost USDW. Finally, any such wells should have a casing pressure test against a temporary packer or plug to demonstrate the long string's mechanical integrity at least annually. These additional requirements are consistent with the criteria used by the Texas Railroad Commission for granting exceptions to the tubing and packer requirement. In short, tubing and packer is far and away the preferred practice for reducing the risk of environmental release, and the bar for not using them should be very high.

20. Enhance internal and external mechanical integrity testing requirements: EDF has suggested edits that provide methods for testing, appropriate well conditions during testing, thresholds for determining whether a test is successful, and a testing schedule for temporarily abandoned wells. These recommendations are appropriately differentiated for different types of injection wells. The edits are designed to reflect modern practices and ensure that the tests are effective.

21. Provide a timeline for plugging temporarily abandoned wells: EDF inserted a provision to require temporarily abandoned wells to be repaired or returned into service within two years, or be properly plugged and abandoned. EDF is not aware of any statute or rule that otherwise compels plugging aside from at the discretion of the Division, but in order to create a uniform and protective standard, EDF suggests two years as a cut-off. Wells left unrepaired and out of service for longer than this time frame run an unacceptable risk of causing pollution. The Division should seriously consider adopting this timeline, and potentially even a shorter one, for such wells.

22. Provide a timeline for notifying the Division if an operator ceases injection or withdrawal: the Division provides a list of reasons why an operator should cease injection (for example, if there is indication of a loss of fluid confinement). EDF's edits provide a timeline for notifying the Division, with an acceleration for potential pollution events.

23. Provide guidance as to requirement testing of master valves and wellheads: these pieces of surface equipment provide critical operational functionality and environmental protection at the interface of wells and pipelines. They should undergo monthly manual testing and annual isolation pressure testing to ensure proper performance. The edit also provides language for reporting test results.

24. Require Class II injection wells to be equipped with a device to terminate injection if maximum pressures are exceeded: this provision is included, for example, in Ohio's Class II injection well rules, and ensures that wells are not accidentally over-pressurized, which can risk the integrity of both the well and the formation.

25. Enhance protocols for radioactive tracer tests, temperature surveys and cement evaluation: EDF has provided technical edits to help the proposed protocols reflect modern practices. Providing detailed guidance to operators on how to conduct these tests that determine a well's integrity will help ensure their uniformity and accuracy.

It is worth noting that this list is not complete, and EDF has made a variety of other small edits for clarity throughout the document, for which we urge due consideration.

(2) <u>In addition to items covered in the discussion draft and the issues raised above, what follows is a partial list of other issues EDF believes the Division will have to address in the current or upcoming rulemaking:</u>

1. Corrosion testing: the Division should require regular, perhaps annual, corrosion testing of all injection wells. Corrosion was apparently a problem for the leaking Aliso Canyon well, and the emergency rules call for information from operators on corrosion problems and mitigation strategies. The Division's requirements for corrosion testing prior to returning Aliso Canyon wells to service are a start, but a more comprehensive

and universally applicable rule for corrosion testing should be developed and implemented. Corrosion testing is one of the few ways of detecting a potential problem before undesirable outcomes occur, and it will be important to include corrosion testing as part of the Division's ultimate regulatory package. Additionally, by identifying the causes of corrosion and applying mitigation controls, operators could dramatically reduce the incidence of corrosion problems in the first place.

2. Definition of continuous monitoring: we noted above that the Division requires continuous monitoring in various contexts, but does not define it. Continuous monitoring can mean different things to different stakeholders – truly continuous like a seismograph? Every second? Every day? – and it should be defined for the sake of uniformity. We leave it to the Division to develop an appropriate definition based on effectiveness and practicality.

3. Well construction rules: all injection and withdrawal wells in California are governed by the Division's well construction rules covering drilling, casing, cementing and related activities, but these are not addressed in the current discussion draft. EDF has not yet conducted a thorough analysis of these rules, but it is likely that some well construction provisions will warrant updating in the near future. For example, current well construction rules do not require reporting surface casing cementing problems to the Division, nor are any cement specifications provided. The Division might consider conducting a general rulemaking on well construction.

4. Temporary abandonment rules: language proposed by both the Division and EDF refer to temporarily abandoned or idle wells. There is no temporary abandonment definition or protocol for onshore wells in the Division's rules. EDF advises the Division to develop a definition and a protocol prior to the finalization of these rules.

5. Plugging and abandonment protocols: in a similar vein to well construction, the Division's general plugging and abandonment rules apply to injection and gas withdrawal wells and should be reconsidered in that context. EDF has already noted that there is no apparent timetable for plugging. Plugging rules should be vetted prior to finalizing this injection rule, or as soon as possible under a general well construction rulemaking.

6. Additional plans: the Division's proposal calls for several plans to be submitted by operators as a part of a permit application, but other types of plans are appropriate as well. These include plans for emergency response, blowout contingency, maintenance and monitoring. EDF has not provided edits at this time to include these plans, which will require considerable guidance from the Division, but they should nevertheless have a place in the Division's final rule on underground injection.

(3) <u>Track changes version of the draft emergency rules:</u>

See attached markup of discussion draft.

Thank you for this opportunity to comment on the discussion draft. EDF looks forward to working with the Division over the coming months as it more fully fleshes out a robust regulatory framework for natural gas storage and underground injection control. If you wish to follow up on any of the items discussed in this letter or attachments, please feel free to contact us by email at sanderson@edf.org, or by phone at 512-691-3410.

Respectfully submitted,

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UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

PRE-RULEMAKING DISCUSSION DRAFT

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CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES

Subchapter 1. Onshore Well Regulations

Article 2. Definitions

1720.1. Definitions

The following definitions are applicable to this subchapter:

(a) "Area of review" means an area that includes a radius around each injection well that is part of an underground injection project, the radius being the greater of (1) or (2).

(1) The radius shall be at least the calculated lateral distance in which the pressures in the injection zone may cause the migration of the injection fluid, or the formation fluid out of the intended zone of injection; and

(2) The radius shall be at least:

(A) One quarter mile for an injection well that is not a cyclic steam; ~~or~~

(B) 300 feet for an injection well that is a cyclic steam well; or~~.~~

(C) An area of review other than described in this rule that is designated by the Division.

(b) **"**Surface expression**"** means a flow of fluid, or material to the surface that is not through a well and that is caused by injection operations.

(c) "Surface expression containment measure" means an engineered measure undertaken in accordance with all state and local requirements to contain or collect the

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fluids from a surface expression, including but not limited to subsurface collection systems, collection wells, cisterns, culverts, French drains, collection boxes, or gas hoods or other gas collection system.

(d) "Freshwater" means water that contains 3,000 TDS or less.

(e) "Internal mechanical integrity" means that there is no significant leak in the tubing, casing, or packer.

(f) "External mechanical integrity" means that there is no vertical fluid movement (gas or liquids) exterior to any of the well casings that is (1) into or between USDWs, (2) vertically upward from the permitted injection zone into an unpermitted interval, (3) into or between any unauthorized geologic formations, or vertically upward in such a manner to create pressure on any annular space.

(g) "Wellbore diagram" means a diagram or schematic of any wellbore showing the diameters of the wellbores, casing sizes and depths, cementing information of each casing string, and tubing and packer types and configuration.

(h) "Injection well" means any well that is permitted by the Division to inject fluid for the purpose of disposal, enhanced recovery, or for hydrocarbon storage.

(i) "Withdrawal well" means any well that is used for the withdrawal of gas from a gas storage project.

(j) "Fluid" means any material or substance which flows or moves whether in a semi-solid liquid, sludge, gas, or any other form or state

(k) "Underground injection project" means a location with a defined, continuous three-dimensional surface and subsurface extent with fixed boundaries in which sustained or continual injection into one or more wells occurs over an extended period in order to add fluid to a zone for the purpose of enhanced oil recovery, disposal, ~~or~~ gas storage, or similar activities. Examples of underground injection projects include waterflood injection, steamflood injection, cyclic steam injection, injection disposal, and gas storage projects.

(l) "Underground source of drinking water" or "USDW" mean an aquifer or its portion that contains fewer than 10,000 TDS and has not received an aquifer exemption ~~aquifer exemption~~ proposed by the Division and approved pursuant to the Code of Federal Regulations, title 40, section 144.7.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

Article 3. Requirements

1724.6. Approval of Underground Injection ~~and Disposal~~ Projects

(a) A Project Approval Letter shall ~~Approval must~~ be obtained from ~~this~~ the Division before any injection or withdrawal occurs as part of an underground injection project.~~subsurface injection or disposal project can begin. This includes all EPA Class II wells and air- and gas-injection wells.~~ The operator requesting approval for such a project must provide the appropriate Division representative ~~district deputy~~ with the data specified in Section 1724.7 and any data that, in the judgment of the Division~~Supervisor~~, are pertinent and necessary for the proper evaluation of the proposed project.

(b) The Project Approval Letter shall specify the location and nature of the underground injection project, as well as the condtions of the Division's approval. Modification of an underground injection project is subject to approval by the Division and shall be noted in either an addendum to the Project Approval Letter or a revised Project Approval Letter. Underground injection project operations shall not occur unless consistent with the terms and conditions of a current Project Approval Letter. Regardless of the contents of a Project Approval Letter, injection or withdrawal suspended under Section 1724.10(l) shall not resume without subsequent approval from the Division.

(c) The Division will review underground injection projects to verify adherence to the terms and conditions of the Project Approval Letter, and will periodically review the terms and conditions of the Project Approval Letter to ensure that they effectively prevent damage to life, health, property, and natural resources. Approval of an underground injection project is at the Division's ongoing discretion and a Project Approval Letter is subject to suspension, modification, or rescission by the Division.

(d) If the Division determines that operation of an underground injection project is inconsistent with the terms and conditions of a current Project Approval Letter, or otherwise poses a threat to life, health, property, or natural resources, or endanger USDWs then upon written notice from the Division injection or withdrawal operations shall cease immediately, or as soon as it is safe to do so.

(e) Within 60 days after transfer of an underground injection project to a new operator, the new operator shall meet with the Division staff to ensure complete understanding of the parameters and conditions of the Project Approval Letter.

(f) No such transfer shall relieve the existing operator of any obligation or violation accrued under these rules, nor shall it relieve the operator of the obligation to plug and abandon wells associated with the project until all requirements of these rules have been met and all compliance issues are resolved.

(g) Underground injection projects already in operation at the time these rules are adopted shall receive a Project Approval Letter within one year of adoption of these rules from the Division that such projects are in compliance with all provisions of this Subchapter. During the year, such projects must comply with all rules intended for

wells not yet in operation, unless granted an exception for good cause. Underground injection projects that fail to receive a Project Approval Letter shall discontinue operations in a manner authorized by the Division that will not cause damage to life, health, property, or natural resources, or endanger USDWs until approval is received.
(h) All injection and withdrawal wells must be part of an underground injection project with a Project Approval Letter.

Note: Authority cited: Section 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.7. Project Data Requirements

~~(Note: See Section 1724.8 for special requirements for cyclic steam projects, and Section 1724.9 for supplementary requirements for gas storage projects.)~~

~~The data required to be filed with the district deputy include the following, where applicable:~~

(a) An underground injection project shall be supported by data filed with the Division that demonstrates to the Division's satisfaction that injected fluid will be confined to the approved zone or zones of injection and that the underground injection project will not cause damage to life, health, property, or natural resources, or endanger USDWs. The operator shall ensure that the data are current and account for all changes to the setting and operation of the project. The data file d with the Division shall at a minimum, include the following:

(1) ~~(a)~~ An engineering and geological study demonstrating that injected fluid will not migrate out of the approved zone or zones through another well, geologic structure, faults, fractures, or fissures, or holes in casing, including but not limited to:

(A) ~~(1)~~ Statement of primary purpose of the project.

(B) ~~(2)~~ Reservoir characteristics of each injection zone, such as porosity, permeability, fluid chemistry, petrophysical properties, mechanical properties, fracture gradient, locations of faults, folds, unconformities, and fractures, average thickness, areal extent, fracture gradient, original and present temperature and pressure, and original and residual oil, gas, and water saturations. The scope of the geologic characterization shall encompass the intended reservoir rock and sealing mechanisms, the confining zones directly ~~vertical interval~~ above and below the intended reservoir, areas where fluid could potentially migrate, and the areas adjacent to the intended reservoir where potential entrapment of migrated fluid could occur.

(C) ~~(3)~~ Reservoir fluid data for each injection zone, such as oil gravity and viscosity, water quality, presence and concentrations of non-hydrocarbon components in the

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associated gas (i.e. hydrogen sulfide), and specific gravity of gas.

(D) A map of the area of review showing the location and status of all wells within and adjacent to the boundary of the area of review. Individual injection wells shall have the area of review delineated around each well. The surface and bottomhole locations, and the wellbore path of directionally drilled wells shall be shown, with indication of the interval penetrating the injection zone of each well in the underground injection project.

(E) ~~(4)~~ Wellbore ~~Casing~~ diagrams, including ~~cement plugs, and actual or cabulated cement fill~~ ~~behind casing~~ all data specified in Section 1724.7.1, of all idle, plugged and abandoned, or ~~deeper-zone~~ producing wells that are within the area of review of each injection well and that penetrate into or through ~~are in the same or a deeper zone as~~ the underground -injection project or gas storage zone, including directionally drilled wells that intersect the area of review in the same or deeper zone. ~~affected by the project, and~~ ~~evidence that plugged and abandoned~~ The wellbore ~~casing~~ diagrams must demonstrate that the wells ~~in the area~~ will not be a potential conduit for fluid to migrate outside of the approved zone of injection or otherwise have an adverse effect on the project or cause damage to life, health, property, or natural resources, or endanger USDWs. At a minimum, the wellbore ~~casing~~ diagrams must demonstrate that:

(i) Plugged and abandoned wells have cement across all perforations and extending at least 6~~5~~00 feet above, if shown by cement fill-up calculation, or 100 feet above, if shown by ~~cement bond log a~~ 360 degree cement evaluation tool capable of showing cement channels or other method approved by the Division, above the highest of the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, the intended zone of injection, or the oil and gas zone; and

(ii) ~~W~~Any wells that are not plugged and abandoned and penetrate into or through the proposed underground injection projectzone of injection shall be plugged and abandoned prior to commencement of injection operations or a proposed alternative corrective action plan, includng isolation of the zone of injection shall be undertaken with the approval ofthe Division. Existing producing or injection wells that are part of the projectand that have not been used for injection or production for more than 180 days shall be considered temporarily abandoned, and shall either demonstrate external and internalmechanical integrity, be repaired and returned to service, or ~~two years~~ have cement plugs emplaced across all hydrocarbon zones, flow zones, corrosive zones, lost circulation zones, the base of

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the USDW interface, and the base of the ~~-~~freshwater interface.

(F) Identification of all wells within the area of the underground injection project ~~r review~~ that do not penetrate into or through the injection zone of the underground injection project, including description of the total depth of the well and the estimated top of the injection zone below the well.

(G) Wells completed into or penetrating through the intended injection zone shall be evaluated for containment assurance for the design of injection operation volumes, injection or gas storage pressures, and flow rates. Based on the history of construction, workovers and tests, ~~T~~the operator should identify, and the Division confirm, wells which ~~may~~ require well integrity testing and/or well logging in order to ~~meet the integrity~~ demonstrate external and internal mechanical integrity~~ion~~ The Division may require ~~select~~ plugged and abandoned wells to be re-opened, re-entered, examined, re-plugged and abandoned, or monitored to manage identified containment assurance issues prior to approval of injection. Additionally, upon the request and with the direction of the Division, periodic field inspections of wells in the AOR that penetrate into or through the injection zone shall be conducted.

(H) ~~(5)~~ The planned well-drilling and plugging and abandonment program to complete the project, including a flood-pattern map, if applicable, showing all injection, production, and plugged and abandoned wells, and unit boundaries.

(I) Maps of the locations of underground disposal horizons, mining, and other subsurface industrial activities not associated to oil and gas production within the area of review of each underground injection project.

(2) ~~(b)~~ A geologic study, including but not limited to:

(A) ~~(1)~~ Structural contour map drawn on a geologic marker unit at or near the top of each injection zone in the project area, identifying all known ~~indicating~~ faults, fault zones, and other ~~lateral containment~~ containing or transmissive geologic features.

(B) ~~(2)~~ Isopach~~ous~~ map of each injection zone or subzone in the project area.

(C) ~~(3)~~ At least one geologic cross section through at least one injection well in the project area. The Division may require additional geological cross sections depending upon subsurface structural geological features identified within the project area.

(D) ~~(4)~~ Representative ~~electric~~ open-hole geophysical log to a depth below the deepest producing or gas storage zone (if not already shown on the cross section), identifying all geologic units, formations, USDW aquifers, freshwater aquifers, and oil or gas zones.

(3) ~~(c)~~ An injection plan, including but not limited to:

(A) ~~(1)~~ A map showing injection facilities.

(B) ~~(2)~~ Maximum proposed ~~anticipated~~ surface injection pressure (pump pressure) and daily rate of injection, by well.

(C) ~~(3)~~ Monitoring system or method to be utilized to ensure that no damage is occurring and that the injection fluid is confined to the ~~intended~~ approved zone or zones of injection. If groundwater monitoring is a required component of the underground injection project, then a groundwater monitoring plan with sampling and analytical documentation shall be provided along with ~~of~~ the results of the consultation with the State Water Resources Control Board or Regional Water Quality Control Board.

(D) ~~(4)~~ Method of injection.

(E) ~~(5)~~ List of proposed cathodic protection measures for plant, pipelines, and wells, if such measures are ~~warranted~~ required by the Division.

(F) ~~(6)~~ Treatment of fluid ~~water~~ to be injected.

(G) ~~(7)~~ Source and analysis of the injection ~~liquid~~ fluid, as specified in Section 1724.7.2.

(H) ~~(8)~~ Location and depth of each water-source well that will be used in conjunction with the project.

(4) The results of step rate tests, conducted in accordance with Section 1724.7.3, for each injection well that is part of the underground injection project. Subject to approval from the Division, this requirement may be satisfied by providing representative step rate test data from ~~select~~ wells within the underground injection project selected by the operator on a basis that is satisfactory to the Division in order to establish a conservative ~~estimated~~ baseline fracture gradient for the entire area of the underground injection project. The Division wil l approve the use of an estimated baseline fracture gradient if, based on consideration of geologic, engineering, and operational factors, it is satisfied that the estimated baseline fracture gradient is lower than the actual fracture gradient that would be encountered anywhere in the area. If an estimated baseline fracture gradient is approved, a higher fracture gradient may be established for a specific well within the underground injection project, if the higher fracture gradient is supported by a well-specific step rate test conducted in accordance with Section 1724.7.3.

(5) ~~(d)~~ Copies of letters of notification sent to offset operators adjacent to the proposed project area and within the area of review of each injection well.

(6) ~~(e)~~ Other data as required for large, unusual, or hazardous projects, for unusual or complex structures, or for critical wells. Examples of such data are: isogor maps, water-oil ratio maps, isobar maps, wellhead diagrams, equipment diagrams, and safety

programs.

(7) Identification of all injection wells that ar e part of the underground injection project and all production or withdrawal wells that are part of the project or that are intended to be affected by the underground injection project.

(8) (a) Any data that, in the judgment of the Division ~~Supervisor~~, are pertinent and necessary for the proper evaluation of the underground injection project.

(b) When a new injection well is added to an underground injection project it is not necessary to duplicate data already provided to the Division, except that updated data shall be provided to the Division if conditions have changed or if more accurate data has become available.

(c) ~~(f)~~ All data filed with the Division under this section shall be submitted electronically and in paper form. All maps, diagram s and exhibits required in subdivision (a) ~~Section 1724.7(a) through (e)~~ shall be clearly labeled as to scale and purpose and shall clearly identify all wells, boundaries, zones, contacts, and other relevant data.

(d) Where it is infeasible to supply all of the data specified in subdivision (a), the Division may accept alternative data, provided that the alternative data demonstrates to the Division's satisfaction that injected fluid will be confined to the approved zone or zones of injection and that the subsurface injection or disposal project will not cause damage to life, health, property, or natural resources.

8) Operators of natural gas storage projects shall submit an automatic fail-safe shut-off safety system plan covering each well in the project to the Division for approval.

(9) Any well equipped with a Subsurface Safety Shut-off Valve (SSSV) shall ensure that the SSSV is properly function tested and calibrated in accordance with the manufacturer's requirements and per API Specification 14A/ISO 10432.

(10) The geologic and hydrogeologic evaluation required under this section for gas storage project shall be certified by a licensed geologist or licensed engineer. The operator of an underground injection project may submit existing geologic and hydrogeologic studies or evaluations in fulfillment of the requirement of this section if those studies have been updated to reflect current conditions at the time of the application and have been certified as such by a licensed geologist or licensed engineer.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Publc Resources Code. Reference:

Section 3106, Public Resources Code.

1724.7.1. Wellbore ~~Casing~~ Diagrams

(a) Wellbore ~~Casing~~ diagrams submitted under Section 1724.7(a)(1)(D) shall adhere to the following requirements:

(1) Wellbore ~~Casing~~ diagrams shall include all of the following data:

(A) API number of the well;

(B) Ground elevation from sea level;

(C) Reference elevation (i.e. rig floor or Kelly bushing);

(D) Base of freshwater;

(E) Base of USDW;

(F) Type, ~~s~~Sizes and weights of casing, liners, tubing, and packer;

(G) Depths of shoes, stubs, and liner tops;

(H) Depths of perforation intervals, open-hole completion, water shutoff holes, cement port, cavity shots, cuts, casing damage, and top of junk or fish left in well;

(I) Diameter and depth of various boreholes;

(J) Cement plugs inside casings, including top and bottom of cement plug, with indication of method of determining;

(K) Cement fill-up behind casings, including top and bottom of cement fill, with indication of method of determining;

(L) Type and weight (density) of fluid between cement plugs;

(M) Depths and names of the formations, zones, and sand markers penetrated by the well, including the top and bottom of the zone where injection will occur and the confining zone above it;

(N) All steps of cement yield and cement calculations performed or cement tops obtained from geophysical logs;

(O) All information used to calculate the cement slurry (volume, density, yield), including but not limited to, cement type and additives, for each cement job completed in each well; and

(P) All of the information listed in this paragraph for all previous re-drilled or sidetracked well bores.

(2) Measured depth and true vertical depth shall be provided for all depths required under subdivision (a)(1).

(3) Wellbore ~~Casing~~ diagrams for directionally drilled wells, shall include surface and

subsurface locations and a wellbore path giving both inclination and azimuth measurements.

(4) Wellbore~~Casing~~ diagrams shall be submitted as both a graphical diagram and as a flat data set.

(b) The designs for all new wells planned to be drilled for a gas storage project at the time of application shall include a signed and sealed certification from a professional engineer.

(c) The designs for any existing wells that are proposed to be converted to gas storage injection or withdrawal wells shall include information demonstrating that these wells have been designed, constructed, and maintained in a way that makes them suitable for injection or withdrawal purposes, with a signed and sealed certification from a professional engineer to this effect.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Publc Resources Code. Reference: Section 3106, Public Resources Code.

1724.7.2. Injection Fluid Analysis

(a) Injection fluid analysis required under this Article shall include testing for all of the following: total dissolved solids; metals listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2)(A); aluminum; antimony; arsenic; barium; beryllium; boron; cadmium; calcium; chromium; cobalt; copper; iron; lead; lithium; magnesium; manganese; mercury; molybdenum; nickel; potassium; selenium; silver; sodium; strontium; thallium; vanadium; zinc; Polynuclear Aromatic Hydrocarbons including, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, benzo(a)pyrene, benzo(g,h,i)perylene, chrysene, dibenzo(a,h)anthracene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, and pyrene; radionuclides including, Gross alpha particle activity, Gross beta particle activity, Radium-226, Radium-228, Strontium-90, Tritium, and Uranium.

(b) Injection fluid analysis required under this Article shall be done by a laboratory that is certified by the California Department of Public Health environmental laboratory accreditation program.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Publc Resources Code. Reference: Section 3106, Public Resources Code.

1724.7.3. **Step Rate Tests**

(a) Step rate tests conducted under Section 17247.3~~(a)(4)~~ shall use fluid and adhere to the following requirements:

(1) When a step rate test is conducted on a forma tion with a permeability of greater than 10 millidarcies the well must be shut in for at least 48 hour prior to the test and the time steps shall be 60 minutes.

(2) When a step rate test is conducted on a forma tion with a permeability of 10 millidarcies or less the well must be shut in for at least 72 hour prior to the test and the time steps shall be 90 minutes.

(3) The first three steps of the step rate test s hall be below the fracture gradient.

(4) Steps shall be conducted at 5%, 10%, 20%, 40%, 60%, 80%, and then at 100% of the proposed injection rate, or until formation breakdown.

(5~~4~~) Real time downhole pressure recording using two downhole digital pressure gauges shall be employed ~~into the well~~ at least 24 hours prior to commencement of the step-rate test, unless an alternative has been approved by the Division.

(6~~5~~) Bottom-hole pressure shall be recorded at a zero injection rate for at least one full time step before the first step of the step rate test and one full time step after the last step of the step rate test.

(7) Instantaneous shut-in pressure and shut-in pressure at 5, 10, 15 and 30 minutes after shutting in the well shall be recorded.

(b) Step rate test data reported under Section 1724.7(a)(4) shall include the injection rate, bottom hole pressure, surface pressure, pump rate volume, and time recorded continuously at a rate of every one second during the step rate test. The step rate test data submitted to the Division shall be raw and unaltered.

(c) The appropriate district office shall be notified at least 24 hours in advance of conducting a step rate test under Section 1724.7(a)(4) so that Division staff may have an opportunity to witness the step rate test.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Publc Resources Code. Reference:

Section 3106, Public Resources Code.

~~**1724.8. Data Required for Cyclic Steam Injection Project Approval**~~

~~The data required by the Division prior to approval of a cyclic steam (steam soak) project include, but are not limited to, the following:~~

~~(a) A letter from the operator notifying the Division of the intention to conduct cyclic steam injection operations on a specific lease, in a specific reservoir, or in a particular well.~~

~~(b) If cyclic steam injection is to be in wells adjacent to a lease boundary, a copy of a letter notifying each offset operator of the proposed project.~~

~~AUTHORITY:~~

~~Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.~~

1724.10. Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects

(a) The appropriate Division representative ~~district deputy~~ shall be notified within 60 days of any anticipated changes in an underground injection project resulting in ~~alteration of conditions originally approved~~ inconsistency with the current conditions of approval, such as: increase in size, change of injection interval, or changes ~~increase~~ in injection pressure. Such changes shall not be carried out without Division approval in accordance with Section 1724.6.

(b) Notices of intention to drill, redrill, deepen, or rework, on current Division forms, shall be completed and submitted to the Division for approval whenever a new well is to be drilled for use as an injection well and whenever an existing well is converted to an injection well, withdrawal well, or observation well, ~~even if no work is required on the well. I~~or if the well is to be reworked. In addition to the notice of intention that may be required under Public Resources Code section 3203, the addition of an injection well to an underground injection project is subject to approval by the Division in accordance with Section 1724.6.

(c) An injection report on a current Division form or in a computerized format acceptable to the Division shall be filed with the Division on or before the 30th day of each month, for the preceding month.

(d) A chemical analysis of the ~~liquid~~ fluid being injected, as specified in Section 1724.7.2, shall be made and filed with the Division at least once every two years, whenever the source of injection ~~liquid~~ fluid is changed or an additional source is introduced, ~~or~~ and as requested by the ~~Supervisor~~ Division.

(e) An accurate, operating injection pressure gauge or pressure recording device shall be installed on every injection or withdrawal ~~whenever a~~ well prior to commencement of injection or withdrawal operations ~~is injecting available at all times, and all injection wells shall be equipped for installation and operation ofsuch gauge or device~~. Pressure gauges or other pressure recording devices shall be installed on the injection tubing and on all casing annuli that are not cemented back to the surface and shall be continuously monitored for pressure changes that might indicate a loss of mechanical integrity. A gauge or device used for injection-pressure recording and testing~~, which is permanently affixed to the well or any part of the injection system,~~ shall be calibrated at least every six months, or as recommended by the manufacturer. ~~Portable gauges shall be calibrated at least every two months.~~ Evidence of such calibration shall be available to the Division upon request.

(f) All injection and production piping, valves, and facilities shall meet or exceed design standards for the maximum ~~anticipated~~ allowable injection pressure, and shall be maintained in a safe and leak-free condition.

~~(f)~~(g) Gas storage injection or withdrawal wells shall be designed and equipped with a redundant wellhead valve system. A master valve assembly shall be attached directly to the production casing and a second master valve assembly on the tubing. Wellhead designs for gas storage wells shall be submitted to the Division for approval.

(h) All injection or withdrawal wells shall be equipped with a tubing and packer, set adjacent to a cemented interval, and within 100 feet above the approved zone of injection. At a minimum, all injection wells shall have at least 100 feet of cement above the injection zone determined by a 360 degree cement evaluation tools capable of showing cement channels, or 250 feet of cement determined by temperature survey, 600 feet of cement determined by calculated fill-up.

(1) Exceptions to tubing and packer injection may be approved by the Division only for Class II injection wells if the Division determines based on documented well integrity evidence that multiple casing strings can protect the USDW and oil zones without the use of tubing and packer, and:

(a) At least two strings of casing set below the base of the fresh water and the base of the USDW and cemented to surface,

(b) At least one string of casing set at least to a depth where the casing shoe can withstand the maximum allowable injection and cemerted to the surface; and

(c) Allowable pressure may not overcome hydrostatic head of lowermost USDW

(2) Wells that are approved for casing injection will be required to perform a casing pressure test against a temporary packer/plug to demonstrate mechanical Integrity of the long string casing at least annually.

~~All injection wells, except steam, air, and pipeline-quality gas injection wells, shall be equipped with tubing and packer set immediately above the approved zone of injection within one year after the effective date of this act. New or recompleted injection wells shall be equipped with tubing and packer upon completion or recompletion. Exceptions may be made when there is:~~

~~(1) No evidence of freshwater-bearing strata.~~

~~(1) (2) More than one string of casing cemented below the base of fresh water.~~

~~(2) (3) Other justification, as determined by the district deputy, based on documented evidence that freshwater~~ USDW ~~and oil zones can be protected without the use of tubing and packer.~~

~~(g)~~(i) Data as required per Section 1724.7 shall be maintained to show performance of the project and to establish that no damage to life, health, property, or natural resources, or endanger USDWs, is occurring by reason of the project. ~~Injection shall be stopped if there is evidence of such damage, or loss of hydrocarbons, or upon written notice from the Division.~~ Project data shall be available for periodic inspection by Division personnel.

~~(h)~~(j) Maximum allowable surface pressure shall equal top perforation depth or top of open-hole completion, in true vertical depth, multiplied by the difference between the injection gradient and the injectate fluid gradient (MASP = (IG – IFG) * TVD). The injection gradient used for this calculation shall be 0.~~95~~ 80 multiplied by the fracture gradient as determined under Section 1724.7(a)(4). The Division may approve a higher maximum allowable surface injection pressure (up to an injection gradient of 0.95) based on a conclusive demonstration by the operator that the confining zone and the wells are capable of operating at that pressure throughout the life of the project and the injected fluid will remain confined to the intended zone of injection.

~~To determine the maximum allowable surface injection pressure, a step-rate test shall be conducted prior to sustained liquid injection. Test pressure shall be from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first. Maximum allowable surface injection pressure shall be less than the fracture pressure. The appropriate district office shall be notified prior~~

~~to conducting the test so that it may be witnessed by a Division inspector. The district deputy may waive or modify the requirement for a step-rate test if he or she determines that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection.~~

~~(i)~~(k) An initial mechanical integrity test (MIT) must be performed on all injection and withdrawal wells to ensure the injected fluid is confined to the approved zone or zones. An MIT shall consist of a two-part demonstration as provided in ~~subsections~~ subdivisions (k~~j~~)(1) ~~and (2).~~ - (5).

(1) Prior to commencing injection or withdrawal operations, each injection or withdrawal well must pass a pressure test of the casing or casing-tubing annulus ~~-tubing annulus~~ to determine the absence of leaks. Thereafter, the ~~annulus of~~ casing or casing-tubing annulus of each underground injection project well must be tested at least once every five years; ~~prior to recommencing injection operations following the repositioning or replacement of downhole equipment;~~ or whenever requested by the ~~appropriate~~ Division ~~-district deputy~~. The casing or casing-tubing annulus shall be tested to the maximum allowable surface pressure, or 200 psi, whichever is greater. With approval from the Division, casing or casing-tubing annulus may be tested at a lower pressure, provided that there is a correspondng reduction of the maximum allowable surface pressure for the injection well. Pressure testing is required of wells subject to this rule whether or not they are of active status. ~~even if the well is no longer an active injection well or gas storage withdrawal well, unless the well is no longer approved for injection or gas withdrawal and it has been converted to observation or is producing oil or gas.~~

~~(1)~~(2) Internal mechanical integrity testing

(a) For Class II wells, the pressure test shall be conducted on the casing-tubing annular space at the maximum allowable surface injection pressure for 30 minutes with no more than a 10% decline. A corrosion-resistant fluid shall be emplaced within the casing-tubing annulus of all wells utilizing a tubing and packer for injection. For approved wells injecting without tubing and packer, a mechanical bridge plug shall be set in the bottom of the production casing and the pressure test approved in accordance to the pass/failure criteriaas in the above.

(b) Gas storage injection and withdrawal wells shal be pressure tested with an inert gas at a test pressure of at least 120% of the maximum allowable injection or gas storage operating pressure. The pressure test shall be for a minimum of 60 minutes with no more than a 10% decline.

~~(2)~~(3) ~~When required by subsection (j) above, injection wells shall pass a second demonstration of mechanical integrity.~~ The second test (external mechanical integrity) of a two-part MIT shall demonstrate that there is no fluid migration behind the casing, tubing, or packer. This may be done by a combination of a tools such as the temperature survey, radioactive tracer, 360 degree cement evaluation tools capable of showing cement channels, or noise log performed in accordance with Section 1724.10.1, or other methods approved by the Division that demonstrate~~s~~ external mechanical integrity. The operator shall submit a plan stating the toolor combination of the tools to be used to demonstratethe second test of a two-part MIT to the Division for approval. At a minimum, Class I wells shall be evaluated using a cement evaluation tool, and gas storage wells shallbe evaluated using a combination of cement evaluation tool and temperature/noise logging.

~~(3) T~~The second part of the MIT must be performed and results approved by the Division prior to commencement ~~within three (3) months after~~ ~~comm encem ent of i~~ of injection or withdrawal operations. ~~has commenced.~~ Thereafter, ~~water-disposal~~ injection and withdrawal wells shall be tested for external mechanical integrity at least once each year, or on a testing schedule approved by the Division based upon consideration of the age of the well, geology, andoperational factors~~; waterflood wells shall be tested at least once every two years; and steamflood wells shall be tested at least once every five years~~. Such well testing for mechanical integrity shall also be performed following any significant anomalous rateor pressure change, any subsurface wellbore remedial action, or whenever requested by the Division. The second part of the MIT is not required if the injection or withdrawal well becomes ~~is~~ temporarily abandoned~~inactive~~, but shall be performed after ~~within~~ 180 days of the injection or withdrawal well becoming inactive, andevery 180 days until the well is returned to service or permanently plugged and abandoned ~~three months after recommencing injection~~.

The second part of the MIT is not required for a cyclic steam well that has never injected more than 100 gallons per foot. ~~appropriate Division district deputy . The MIT schedule may be modified by the district deputy if supported by evidence documenting good cause.~~

- (3) All anomalies encountered during either part o f the required MIT shall be reported and explained to the Division within 24 hours.

(4) If an injection well becomes temporarily abandoned and is not repaired and

returned to service within two years, the well shall be plugged and abandoned in accordance with Division regulations.

(5) The appropriate Division representative ~~district office~~ shall be notified at least 48 hours in advance of ~~before~~ performing either part of the MIT required under this subdivision so that Division staff ~~before such tests/surveys are made, as a Division inspector~~ may witness the operations. Copies of logging surveys and test results shall be submitted electronically to the Division within 3~~6~~0 days.

(~~k~~l) Injection wells and related facilities shall be continually monitored in order to allow for the discovery and correction of abnormal operating conditions, as follows:

(1) Wellheads, well safety systems, well piping and site locations shall be inspected for operability, leaks and mechanical or other failures~~ults~~.

(2) Wellhead injection pressure and injection flow rate shall be monitored for unexpected changes indicative of a mechanical failures~~ult~~.

(3) Monitoring well pressures or fluid levels shall be monitored for unexpected changes indicative of mechanical failure~~ult~~.

(4) All w~~W~~ell annuli~~us~~ not cemented to the surface and injection pressures or vents shall be monitored continuously for changes.

(~~l~~m) The operator shall cease ~~injection~~ injection or withdrawal immediately ~~into an injection or withdrawal well,~~ and notify the Division immediately in the event of a release ((3) or (4) below) or otherwise within 24 hours, and shall not resume injection ~~into or~~ withdrawal ~~the well~~ without subsequent approval from the Division if any of the following occur:

(1) Mechanical integrity testing required under subdivision (j) has not been performed on the well, or notification and results required under subdivision (j)(4) have not been provided to the Division;

(2) The well failed a mechanical integrity test or demonstration, or there is any other indication that the well lacks mechanical integrity;

(3) There is any indication that fluids or gases being injected into the well are not confined to the intended zone of injection;

(4) There is any indication of that damage to life, health, property, or natural resources, or loss of hydrocarbons is occurring by reason of the project;

(5) The operator did not provide information regarding the well as required under Public Resources Code section 3227;

(6) The well has been inactive for more than two years~~; or~~

(7) The Division instructs the operator in writing to suspend injection or withdrawal operations.

(n) Within sixty days of the effective date of this section, unless the Division authorizes additional time, and on the following schedule thereafter, the operator of an underground gas storage project shall perform a monthly operational manual test of the master valve and wellhead pipeline isolation valve by opening and closing the valves to ensure the valves are in proper working order. An annual isolation pressure test shall be performed on each gas storage injection and withdrawal well to demonstrate that the equipment is properly functioning and verifies the ability to isolate the well. The operator shall submit documentation of the results of annual pressure testing done under this subdivision within 10 days of completing the testing, but shall immediately notify the Division if testing indicates a lack of function or failure.

(o) ~~(k)~~ Additional requirements or modifications of the above requirements may be required by the Division ~~necessary~~ to fit specific circumstances and types of projects. Examples of such additional requirements or modifications are:

(1) Injectivity tests.

(2) Graphs of time vs. oil, water, and gas production rates, maintained for each pool in the project and available for periodic inspection by Division personnel.

(3) Graphs of time vs. tubing pressure, casing pressure, and injection rate maintained for each injection well and available for periodic inspection by Division personnel.

(4) List of all observation wells used to monitor the project, including depth and wellbore diagram, indicating what parameter(s) each well is monitoring (i.e., pressure, temperature, etc.), submitted to the Division annually.

(5) List of all injection-withdrawal wells in a gas storage project, showing casing-tubing and casing- integrity test methods and dates, the types of safety valves used, submitted to the Division annually.

(6) Isobaric maps of the injection zone, submitted to the Division annually.

(7) Notification of any change in waste disposal methods.

(p) All Class II injection wells shall be equipped with an automatic shut-off device set to terminate injection operations if the permitted maximum allowable surface injection pressure on any injection pump is exceeded.

AUTHORITY:

Note: Authority cited: Section 3013, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.10.1. Mechanical Integrity Testing

(a) In addition to all other applicable federal, state, and local requirements, a radioactive tracer performed under Section 1724.10(k~~j~~)(2) shall adhere to the following:

(1) Testing must be conducted while injecting, an d the operator shall ensure that adequate fluid ~~water~~ can be supplied for the test. The injection rate shall be governed by the ability of the operator to track the radioactive tracer as it moves downward, but the injection rate should be as close to the maximum injection rate as practical.

(2) There shall be an adequate pressure different ial across the tubing wall in order for the for the test method to be valid.

(3) The casing valve must be opened during testing and there must be no fluid flow. If fluid flow continues from the casing valve, the casing-tubing annulus shall be evaluated.

(4) Gamma ray detector sensitivity shall be set s o that lithologic effects are just identifiable.

(5) The spectral gamma ray detector must be centralized to the extent feasible.

(6) A tool sketch showing tool diameter along with ejector and detector spacing should be on the log header. Spacing shall be verified by measurement at the surface.

(7) Caliper surveys are required if scale or other buildup is present within the wellbore to a degree that may interfere with the test.

(8~~5~~) A baseline ~~background~~ spectral gamma ray log survey shall be run over the interval to be tested and shall be recorded before any radioactive material is ~~introduced~~ ejected into the well.

(9~~6~~) The test shall record measurements over a period of three to five minutes with the tool stationary at two points which are representative of the extremes of natural radiation within the interval to be tested.

(10~~7~~) The release of a slug of radioactive material must be above the interval to be tested. Slug ejection duration should not change from shot to shot.

(11~~8~~) The slug of radioactive material shall be followed with the logging tool or make repeated passes upward through the slug as it moves down the well. All logging shall be done at a single logging speed which is appropriate for the injection rate to allow quantitative measurements of deflections to be evaluated.

(12~~9~~) If repeated passes are used, the logs resulting from the slug-tracking exercise should overlap so that the return of radioactivity to the level which existed before the slug's passing is demonstrated for the entire length of the section of the well being tested. The logs of all passes should be presented as a composite log on a common depth track. If means to differentiate the log traces are available no other presentation is required. If the traces cannot be differentiated on the composite log, they should also be presented individually.

(13~~0~~) After any ejection, the slug of radioactive material must be followed until it has moved below the interval being tested. If the slug splits, both slug portions must be accounted for.

(14~~1~~) After completion of the passes, a final log should be made through the entire tested interval to check for residual radioactivity which might be associated with exit of tracer material from the well bore.

(15~~2~~) If a well is injecting at a rate that creates a fluid velocity greater than one foot per second, radioactively treated beads shall be introduced into the well and evaluated according to parts 8 through 11 above.

(16~~3~~) Steam injection wells shall be tested using an inert gas tracer.

(b) A temperature log performed under Section 1724.10(k~~j~~)(2) shall adhere to the following:

(1) The well must be taken off injection at least 24 hours but not more than 48 hours prior to performing the temperature log to allow for stabilization, unless an alternate duration has been approved by the Division.

(2) All casing and all internal annuli shall be completely fluid filled.

(3~~2~~) The logging tool shall be calibrated and centralized to the extent feasible.

(4~~3~~) The well must be logged from the top of the well to the bottom ~~surface downward~~, lowering the tool at a rate of no more than 30 feet per minute.

(5~~4~~) If the well has not been taken off injection for at least 24 hours before the log is run, comparison with either a second log run six hours after the time the log of record is started or a log from another well at the same site showing no anomalies shall be available to demonstrate normal patterns of temperature change.

(6~~5~~) The log data shall be provided to the Division electronically in either LAS or ASCII format.

(c) A noise log performed under Section 1724.10(k~~j~~)(2) shall adhere to the following:

(1) Noise logging may not be carried out while injection is occurring.

(2) All casing and all internal annuli shall be completely fluid filled.

(3~~2~~) Noise measurements must be taken at intervals of 100 feet to create a log on a coarse grid.

(4) Noise logging shall occur upwards from the bottom to the top of the well.

(5~~3~~) If any anomalies are evident on the coarse log, there must be a construction of a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

(6~~4~~) Noise measurements must be taken at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

(A) The base of the lowermost bleed-off zone abov e the injection interval;

(B) The base of the lowermost USDW; and

(C) In the case of varying water quality within t he zone of USDW, the top and base of each interval with significantly different water quality from the next interval.

(7~~5~~) Additional measurements must be made to pinpoint depths at which noise is produced.

(8~~6~~) A vertical scale of 1 or 2 inches per 100 feet shall be used.

(d) Cement evaluation logging performed under Section 1724.10 (j) (2) shall adhere to the following:

(1) Cement evaluation tools shall be calibrated an d centralized to the extent feasible.

(2) Cement evaluation tools shall be run first under surface pressure and then under pressure of at least 1500 psig.

(3) If gas is present within the casing where cement evaluation is being conducted, then a padded cement evaluation tool shall be run in lieu of an acoustic tool.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.11. ~~-~~Incident Response

(a) For the purposes of this section, "reportable incident" means any of the following:

(1) A mechanical integrity test or logging survey indicates that an injection well lacks integrity or is otherwise incapable of performing as approved by the Division;

(2) A failure, breach, or hole in the well tubing or packer;

(4) A failure, breach, or hole in the well casing , including failures above and below a packer;

(5) The migration or movement of any amount of in jection fluid to an unpermitted zone; or

(6) Any other incident or occurrence that indicat es fluid is not or may not be confined to the approved injection zone, or that indicates the injection well endangers a USDW, threatens human health, public safety or the ~~environment~~environment (e.g., apparent

detection of gas outside the production casing or wellhead or increased pressure(s) observed beyond the storage zone).

(b) In the event of a reportable incident, the operator of the well must notify the appropriate district office immediately upon discovering the reportable incident. The operator shall consult and share information with the Division.

(c) The operator shall comply with all operational and remedial directives of the Division, including but not limited to immediately ceasing injection operations at the well(s) in question.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Publc Resources Code. Reference: Section 3106, Public Resources Code.